13

Contractual Innovation in the U.K. Energy Markets: Enron Europe, The Eastern Group, and the Sutton Bridge Project

Co-written with Peter Tufano

On December 4, 1996, Stewart Seeligson of Enron Europe and Paul Danielsen of The Eastern Group shook hands and said goodbye as they left yet another late night negotiating session. These two men and their colleagues had met at least three times weekly over the past two months as they attempted to reach an agreement on an innovative business relationship. Seeligson, who had been transferred recently from the risk management department of Enron's global headquarters in Houston, was a member of Enron's asset development team in London. Danielsen was the Head of Contract Trading at Eastern Electricity, the fourth-largest power generator and one of the largest marketers of natural gas in the United Kingdom. The deal that had occupied their attention would deliver to Eastern much of the economics of building a new combined cycle gas turbine (CCGT) power station.

The innovative deal would give Eastern the right to run a "virtual" power plant at will. Enron would sell to Eastern a long-term option to convert natural gas into electricity. Enron planned to hedge its exposure by constructing an actual CCGT plant and by trading in the gas and electric markets. While Eastern's right to receive power proceeds and Enron's right to operate the plant were similar in character, there was no legal or physical connection between Enron's physical plant and Eastern's virtual plant.

Professors Benjamin C. Esty and Peter Tufano, assisted by Research Associate Matthew Bailey, prepared this case. HBS cases are developed solely as the basis for class discussion. Cases are not intended to serve as endorsements, sources of primary data, or illustrations of effective or ineffective management.

Seeligson and Danielsen had agreed on a 13-page, single-spaced term sheet describing the proposed deal, but still had to resolve many issues before they could draft a more definitive agreement. This structure was vastly different from the traditional independent power plant (IPP) structure, and both men would have to convince their superiors of its wisdom—once they had explained how it worked.

THE U.K. ENERGY MARKETS

Based on the principle that energy was "the lifeblood of economic activity and social welfare," the European Commission (EC) favored an integrated energy market with full and open competition in both gas and electricity. In fact, the Commission was drafting a Directive in late 1996 that required energy deregulation for all member countries. The United Kingdom, which began the process of deregulation with the passage of the Electricity Act of 1983 and, more recently, the Electricity Act of 1989, was ahead of the EC in terms of deregulation. The 1989 Act mandated privatization of the U.K. power market and restructuring along functional lines according to a phased-in schedule. Similarly, the Natural Gas Acts of 1986 and of 1995 created the structure for a deregulated gas market. Given this rapidly changing business environment, both Enron and Eastern saw integration of energy markets as offering enormous commercial opportunities.

THE POWER MARKET

Deregulation in the power market introduced competition at almost every stage in the industry: generation, transmission, distribution, and supply. Generation involved the production of electricity. Although the United Kingdom had over 40 licensed generators of power, three firms (National Power plc, PowerGen plc, and British Energy plc) accounted for 77% of power generation in 1995.[1] Coal and oil were burned to produce 40% of generation capacity, nuclear combustion accounted for 25%, gas accounted for 25%, and the remainder was obtained through imports or other nonfossil fuels. To permit economies of scale, regulators mandated that transmission—the transfer of electricity across high-voltage wires known as the "grid"—be carried out by a single firm, the National Grid Company. Distribution, the delivery of electricity via low-voltage wires to end users, and supply, the sale of electricity to consumers, were done by Regional Electric Companies (RECs). The Electricity Act of 1989 created 12 RECs and made them responsible for supplying electricity to customers who had not yet been phased into the new competitive market. Eastern was the largest of the 12 RECs.

Total U.K. electricity sales were 280,000 gigawatt hours (GWh) in 1995 and were growing about 1% per year. The price of electricity was determined by the "pool," an auction mechanism in which all generators participated. Each day by 10:00 A.M., generators submitted schedules detailing how much power they were willing to deliver for each half-hour time slot for the next day and at what price.[2] Arranged in ascending order based on price (in "merit order"), these bids formed the supply schedule for power for each half-hour period.

The National Grid Company forecasted daily demand based on historical models of actual demand. Each day at 4:00 P.M., it announced the next day's "pool" price for

[1] Electricity Association, *Electricity Industry Review* (January 1999).

[2] Given the concentration of generating capacity in the United Kingdom, there was some political debate over whether electric prices represented "fair" market prices.

each half-hour period, which was equal to the bid price from the most expensive generating unit dispatched (instructed to generate electricity during that time slot) in order to meet system demand. The cost of this marginal generator was known as the System Marginal Price (SMP). All generators selected to provide power during a given half-hour period received the same Pool Purchase Price (PPP), an amount equal to the sum of SMP plus a capacity payment that reflected the projected tightness of supply. From the demand side, consumers paid the Pool Selling Price (PSP), an amount equal to the sum of the PPP plus an "uplift" component that reflected the cost of maintaining the system; uplift added a fairly constant 8% to the PPP. In 1995 and 1996, the average SMP was £19.40 per megawatt hour (MWh), PPP was £23.86 per MWh, and PSP was £25.90 per MWh. The Appendix presents data on electric and gas markets, and in particular Appendix Exhibit 13-A1 provides a plot of the average daily PPP over the period from 1994 to 1996.

Given the pool mechanism, electricity prices varied every half-hour during the day. Appendix Exhibit 13-A2 reports the mean and median half-hourly prices over the previous two years, for both weekdays and weekends. Prices fluctuated in response to a variety of short-term, seasonal, and long-run factors, including variations in the cost of fuel (e.g., gas vs. oil), weather, plant failures, plant utilization rates, holidays, changes in generation technology, and the economy's rate of long-run growth. During the 1990s, the monthly average PPP had ranged from as low as £12/MWh in early 1995, to as high as £50/MWh when the system was stressed by strikes and failures of certain peak load generators. This variation in monthly average prices masked extraordinary variation in the daily and half-hourly intraday prices, as measured by the volatility of energy prices (see Appendix Exhibit 13-A3).

RECs bought power from the pool at the volatile PPP, and sold power to consumers at less volatile prices. They were therefore exposed to fluctuations in power prices. To hedge out PPP fluctuations, participants in the power market had begun to create risk management contracts. Power traders, like those at Enron and Eastern, bought and sold spot electricity along with forward and option contracts. Power traders were faced with the challenge—and the opportunity—of dealing in rapidly changing and volatile markets. There was some liquidity in forward contracts for maturities of four to five years, but longer dated forward contracts were infrequent, with only perhaps 10 to 20 transactions maturing beyond five years. Because it was not possible to store electricity, even rudimentary forward curves for power were highly volatile. For very long-term forward contracts, the forward price was often thought to be related to the operating costs that would be incurred by newly built efficient power plants. Given the large uncertainty in longer-term forward curves, the bid-ask spreads for these contracts were substantially larger than for shorter-dated contracts. Appendix Exhibit 13-A4 reflects one set of estimates for forward prices as of late 1996, which show a slight long-run reduction in the forward prices over time.

Without information on actively traded option prices, it was not possible to extract implied volatilities of electric prices. However one could estimate the historical volatility of power. Naïve calculations of historical volatilities showed extraordinary levels of volatility, peaking above 1,000% per annum for intraday prices (one half-hour period to the same period the next day), 600% for volatility of average daily prices, and 200% for volatilities of average weekly prices. However, these calculations failed to take into account the extreme regularities in electric prices (due to predictable intraday or seasonal patterns) and the strong mean reversion in prices. For example, in Appendix Exhibit 13-A1, there are large spikes in the price of power in late 1995 and early 1996. The price rapidly subsided after these spikes, consistent with strong mean reversion of prices.

After controlling for these factors, the volatilities acknowledged by traders were considerably lower—under 50% per annum for short dated options as shown in Appendix Exhibit 13-A4. By this one set of estimates, volatilities for very long dated power options could be under 10% to 15%, considerably below the levels of volatility currently being experienced. This reduction in volatility over time was, however, by no means certain.

Despite the ongoing regulatory and political discussions about how to set pool prices, both Enron and Eastern believed that the informational and strategic benefits of early involvement in power (and gas) markets were substantial. For this reason, they were committed to the markets and staffed their trading operations accordingly.

THE NATURAL GAS MARKET

Just as deregulation created a legal separation between the segments of the power industry, it separated the transportation (pipelines) from the supply of gas. Transco managed the National Transmission System (NTS) and was responsible for setting prices for gas transportation. There were approximately 50 gas suppliers, or marketers, in the United Kingdom in a market that had annual sales of £10 billion.

In the short run, gas prices, like electricity prices, fluctuated in response to temporary supply and demand imbalances. Unlike electricity, however, gas could be stored. As a result, gas prices were much less volatile than power prices, especially on an intraday basis. A second difference between the two markets was that gas indices were set daily instead of half hourly. Appendix Exhibits 13-A5 and 13-A6 show the price and historical volatility of U.K. gas, respectively. During 1995 and 1996, the average price of gas per MMBtu was £1.15 and £1.28, respectively. In the longer term, there were different scenarios about how tight gas supplies might be relative to demand, as a function of economic growth, adoption of gas technology for power generation, and new supplies of natural gas.

Traders created a variety of contracts that allowed gas suppliers and consumers to adjust their exposures to price fluctuations.[3] As of late 1996, there were no exchange-traded contracts on gas delivered in the United Kingdom. However, private gas traders and marketers offered over-the-counter (OTC) contracts including natural gas swaps, forward contracts, and options. Public quotations of these forward contracts were reported on maturities of one year or less. The market for longer-dated forwards and options was relatively thin. Appendix Exhibit 13-A7 reports a set of representative forward prices and option volatilities as of late 1996.

The relationship between gas and electricity prices was complex and changing. Gas was used for purposes other than electricity generation, and electric power prices were set by the cost of the marginal power producer, which in many cases did not use natural gas as a fuel. As a result, short-run correlations between gas and electricity prices were under 10% at the daily level and approximately 0% at the monthly level. Nevertheless, industry analysts expected the correlation to be much higher, possibility as high as 20% to 40% in the longer term as a greater fraction of electricity was generated from gas.

THE EASTERN GROUP

The Hanson Group PLC, a diversified U.K. holding company, purchased The Eastern Group in August 1995 for £2.5 billion. The Eastern Group, the holding company for

[3] See the Harvard Business School case study entitled "Enron Gas Services" (No. 294-076) for a description of contracting in the natural gas industry in the United States.

EXHIBIT 13-1A

FINANCIAL SUMMARIES FOR THE EASTERN GROUP (ALL FIGURES IN £ MILLIONS)

	1995/1996[a]	1994/1995	1993/1994
Revenue	£2,119	£2,061	£1,846
Cost of Sales	1,709	1,507	1,336
Gross Profit	410	554	511
Operating Costs	367	302	316
Operating Profit	43	252	195
Profit Before Tax	258	204	177
Profit After Tax	220	141	123
Total Assets	2,364	2,053	1,545
Long-term Liabilities	682	487	—
Shareholders' Equity (Book Value)	1,189	832	870
Shareholders' Equity (Market Value)[b]	N/A	1,424	1,783
Operating Cash Flow	53	199	431
Debt-to-Equity (Book Value)	57%	58%	0%
Debt-to-Total Capital (Book Value)	36%	31%	0%
Interest Coverage[c]	6.62	7.58	11.12
Bond Credit Rating	Aa3	Aa1	Aa1

[a] Fiscal year ending March 31.

[b] The value of Eastern is not available for March 1996 due to its acquisition by Hanson plc.

[c] As measured by the ratio of earnings before interest, tax, depreciation and amortization (EBITDA) to total interest.

Source: Adapted from Global Access and Bloomberg.

Eastern Electricity and Eastern Natural Gas, served more than 3 million customers in northern London and eastern England. Exhibit 13-1a provides summary financial data on The Eastern Group.

Eastern's business model was more extensive than merely distributing electricity to consumers, its formal role as a REC. When Eastern was privatized in 1990, James Smith, Eastern Group's chief executive officer at the time, announced his intention to create a diversified energy company with new generating capacity and natural gas resources. The logic behind the firm's diversification strategy was to combine gas supply with gas-fired electricity generation to "arbitrage between the two (markets) depending on price."[4] While over 80% of its profits in 1994 had come from its traditional regulated electric distribution businesses, the firm's goal was to have more than half of its profits come from deregulated businesses by 2000. Senior Eastern executives defined the scope of the firm's activity as including "the entire value chain for electricity—from fuel source via the electricity pool to customers' meters."

To accomplish this goal, the firm expanded its operations into both power generation and gas upstream trading and supply. In 1996, Eastern expanded its generating

[4] David Wighton, "Hanson's Bid for Eastern Group," *Financial Times*, August 1, 1995.

capacity by acquiring 6,000 MW of coal-fired generating capacity from National Power and PowerGen after they were required to divest the plants by the Office of Electricity Regulation (OFFER), the U.K. power regulator. The forced divestiture of coal-fired plants, plants that were higher in merit order and were more likely to set pool prices, was done to prevent manipulation by the largest generators who controlled more than 90% of the generating capacity that typically set pool prices. According to Eastern executives, these acquisitions were "a major step towards enhancing competition in generation. This mid-merit and peak capacity complements the successful baseload generation of our Peterborough plant, giving us the ability to compete vigorously across all sections of the generation market."[5] With this capacity, Eastern became the United Kingdom's third largest fossil-fuel generator and its fourth largest power generator.

To permit this acquisition, OFFER relaxed Eastern's "own generation" limit of 1,000 MW, a regulatory restriction on the amount of generating capacity Eastern could own. Collectively, the 12 RECs were allowed to own 8,200 MW of generating capacity, with individual limits ranging from 400 MW to 1,000 MW. The regulators imposed these limits to prevent vertical integration from electricity generation to supply. Eastern already had stations under operation or in construction totaling over 850 MW, so its acquisition of 6,000 MW was unlikely to be repeated in the near future.[6] Like Eastern, other RECs were near their "own generation" limits and were asking the regulators for additional generating capacity.

Eastern also expanded into natural gas during the early 1990s. In what the popular press termed the "dash for gas," Eastern, Enron, and many other firms, sensing opportunities in the rapidly changing gas market, began negotiating for gas supplies. Eastern executives explained their decision:

> Gas is an important part of our strategy . . . all our businesses slot together in a supply chain of electricity. While competition in gas trading may be fierce, we believe our strategy of taking positions in each step of the gas trading chain, from production to retailing, has been, and will continue to be, justified by our results.[7]

As part of this strategy, Eastern signed several large "take-or-pay" contracts and took equity positions in a number of other North Sea fields.[8] With this gas, Eastern then launched a major marketing campaign in March 1996. The strategy paid off in terms of market share as Eastern moved from being the sixth-largest U.K. gas supplier in 1995 to the second largest in late 1996. Eastern's activities in the gas and electric businesses were seen as being strategically related in that it could provide gas and bid for electricity. One Eastern executive noted, "Our emphasis is to create a lot of options, and call the right options at the right time."[9]

[5] Universal News Services, "PowerGen and Eastern Sign Heads of Agreement on Disposal of 2000 MW of Plant," September 18, 1995. A "baseload" plant is a plant with low variable costs that is operated almost all of the time; a "peaking" plant typically has high variable costs and is operated only when the price of electricity is high.

[6] "U.K. Okays Eastern Group purchase of 4,000 MW from National Power," *Electric Utility Week*, June 10, 1994, p. 15. Some observers thought it curious that the Department of Trade and Industry permitted Eastern's vertical integration into generation at a time when it was blocking National Power's and PowerGen's attempts to vertically integrate into distribution through acquisitions of other RECs.

[7] Noni Stacey, "Eastern Eyes Gas Opportunity," *The Scotsman*, June 27, 1995, quoting Eric Anstee, Eastern Group finance director.

[8] In a "take-or-pay" contract, a firm enters into the obligation to pay for a certain fixed quantity of gas at fixed prices. A take-or-pay contract is similar to a forward contract. Enron had also entered into similar contracts for North Sea gas at roughly this same time.

[9] David Knott, "New Players Cut a Swath in U.K.'s Liberalized Gas Market," *Oil and Gas Journal*, October 14, 1996, p. 23.

One potential complication at this time was the fact that the Hanson Group was restructuring its businesses in anticipation of divesting several of them. According to the plan, Hanson was going to spin-off Eastern and Peabody Coal, the world's largest private coal producer, *into a separate energy company sometime in early to mid 1997.* In preparation for a possible divestiture, Eastern was reorganizing its internal operations.

ENRON CORPORATION[10]

Enron Corporation was one of the world's largest integrated natural gas and electricity companies. Led by Ken Lay, its chairman and chief executive officer, and Jeff Skilling, its newly appointed president and chief operating officer, Enron engaged in exploration and production, gas transportation and distribution, and wholesale energy operations and services. Exhibit 13-1b provides summary financial data on Enron Corporation.

In late 1996, Enron was organized into six units: Enron Oil and Gas, which was one of the largest independent oil and gas companies in the United States; Enron Gas Pipeline Group, which operated the firm's U.S. interstate pipelines; Enron Ventures, which provided engineering and construction services; Enron International, which provided merchant and finance services for international integrated energy projects; Enron Renewable Energy Corporation, a supplier of renewable energy; and Enron Capital and Trade Resources (ECT).[11] ECT itself was a firm with many different operating activities, including the following:

- Largest buyer and seller of natural gas in North America
- Largest nonregulated merchant of power in the United States
- Owner and operator of intrastate pipelines
- Manager of the world's largest portfolio of natural gas risk management contracts
- Significant supplier of energy financial services
- Owner and operator of the world's largest natural gas-fired plant in Teesside, United Kingdom
- Largest nonregulated merchant of natural gas in the United Kingdom
- Largest nonregulated merchant of power in the United Kingdom and Nordic region

Enron's scope of business activity ranged from long-term projects to construct and operate power plants to minute-by-minute trading of gas and power. The firm was known for its creativity in solving customer needs and its extreme aggressiveness in attacking new business opportunities. For example, the Wholesale Energy Operations and Services group was one of the leading innovators of a wide variety of risk management and financing contracts in the energy sector. The firm's asset development group tackled some of the most complex power projects around the world including the 1,875 MW power plant in Teesside, England and the 2,450 MW plant in Dabhol, India.[12] Enron strove to link different, and sometimes distant, parts of the firm. In the United States, traders and pipeline experts collaborated to exploit price differentials between gas and

[10] See the Harvard Business School case study entitled "Enron Gas Services" (No. 294-076) for a description of Enron's activities in the U.S. gas markets in the early 1990s.

[11] Skilling had founded the group within the firm that became ECT and was its chairman and CEO before being promoted to president and COO of Enron Corp. in late 1996.

[12] The Harvard Business School cases "Enron Development Corporation: The Dabhol Power Project in Maharashtra, India A & B" (No. 797-085 and No. 797-086) describe the Dabhol project.

EXHIBIT 13-1B

FINANCIAL SUMMARIES FOR ENRON CORPORATION (ALL FIGURES IN $ MILLIONS)[a]

	1995/1996	1994/1995	1993/1994
Revenue	*$13,289*	*$9,189*	*$8,984*
Cost of Sales	10,478	6,733	6,517
Gross Profit	2,811	2,456	2,467
Operating Costs	2,121	1,838	1,751
Operating Profit	690	618	716
Profit Before Tax	855	805	620
Profit After Tax	584	520	453
Total Assets	16,137	13,239	11,966
Long-term Liabilities	7,359	6,716	6,121
Shareholders' Equity (Book Value)	5,070	4,091	3,547
Shareholders' Equity (Market Value)	11,038	9,587	8,326
Operating Cash Flow	1,040	−15	504
Debt-to-Equity (Book Value)	145%	164%	172%
Debt-to-Total Capital (Book Value)	40%	43%	44%
Interest Coverage	4.07	3.48	4.10
Bond Credit Rating	Baa2	Baa2	Baa2

[a] On November 29, 1996, the sterling/dollar exchange rate was $1.6820 per pound sterling.

Source: Adapted from Global Access and Bloomberg.

power prices in distant locations. Looking forward, as the oil, gas, and power sectors converged, the organization would need to find ways to ensure that its various groups worked together to capitalize on new business opportunities.

The proposed transaction with Eastern was attractive from this perspective because it linked the firm's asset development group with its trading operations in a novel fashion. Enron Development Corporation (EDC), Enron's asset development group, had been very successful developing energy infrastructure projects around the world. Historically, this group had very little integration with ECT, Enron's risk management division, which had operated in North America until 1994. But as it became clear that Europe was deregulating its gas and electricity markets, ECT assumed responsibility for the United Kingdom in 1994 and then all of Europe in late 1996.

Prior to 1996, ECT had acted as only a provider of risk management services to the energy markets. Members of the group viewed energy assets, such as power stations and the companies that owned them, as potential counterparties only. Yet this kind of thinking was beginning to change as the traders began to think of assets as potential tools for risk management. Based on this premise, ECT created its own asset development team in Europe comprised of people from EDC with traditional asset development experience and people, like Seeligson, transferred from ECT with energy risk management expertise.

SUTTON BRIDGE AS A TRADITIONAL IPP

In 1995, Enron Europe's asset development team paid $20 million to a consortium of investors for the option to build a 700 MW power plant near Sutton Bridge, Lincolnshire, a town 140 kilometers north of London. The consortium had obtained all of the necessary permits and licenses to develop a CCGT plant but decided to sell the option after it was unable to hedge the electric price risk.

Initially, Enron envisioned structuring the project as an independent power plant (IPP) similar to the structures EDC had successfully used in other regulated markets. Typically, IPP developers created a separate project company and financed it on a nonrecourse basis, which kept the asset off of their balance sheet. The developer's job was to assemble a "contractual bundle" to manage the project's key risks. Richard DiMichele, head of Enron's asset development group, was in charge of negotiating these contracts for Sutton Bridge. An *engineering, procurement, and construction (EPC) contract* would ensure that the plant was built as specified for a set price and by a certain date. An *operating and maintenance contract* would provide for the physical operations of the plant, typically at a fixed fee. A *gas supply agreement* would ensure the plant had access to gas at predetermined prices and quantities. And finally, an offtake or *power purchase agreement (PPA)*, whereby a customer would agree to buy a given quantity of electricity at a given price, would eliminate electric price risk. In regulated and developing markets, the government is typically the counterparty to the PPA; in deregulated markets, private companies—other generators, a distributor, or a large end user—were likely counterparties.[13]

These four contracts were designed to transfer various project risks to parties that were better suited than the development company to handle them. For example, the EPC contract would transfer construction risk to an experienced builder while the PPA would transfer electricity price risk to one of the major electric utilities. From the project's perspective, the goal was to eliminate market risk through long-term, fixed-price contracts. Once the contracts were in place, the IPP would generate an annuity income stream equal to the difference between electricity revenues and gas supply, operating, and financing expenses. Their steady income stream meant IPPs could support highly leveraged capital structures; they often had debt-to-total capitalization ratios of 70% to 90%. In contrast, merchant power plants (MPPs) retained gas and/or electric price exposure. Enron's asset development team initially began negotiating power purchase agreements with representatives from three utilities—Scottish Power, Nuclear Energy, and The Eastern Group—with the intent of constructing an IPP. Because many utilities had lost money on previous PPAs when technological changes lowered generating costs well below the contracted price, they were reluctant to sign long-term, fixed-price contracts. To even consider signing a PPA, they would generally demand equity ownership (if allowed by the regulators). The downside of shared ownership was that it complicated up-front negotiations as well as ongoing operating decisions.

The IPP structure had other drawbacks from Enron's perspective. Given the extensive risk mitigation, the plant could easily turn out to be a low-risk/low-return investment. The combination of a development fee, which might equal 4% of the total investment, and an annuity spread from on-going operations produced acceptable, though not exceptional, returns. More importantly, the structure did not capitalize on Enron's strengths in trading and risk management. For these reasons, the Enron and

[13] The Harvard Business School case, "Tennessee Valley Authority: Option Purchase Agreements" (No. 296-038), details a form of power purchase contract in which a large generator sought to buy options on power. Enron was one of its counterparties in this transaction.

Eastern teams began to contemplate a different structure in September 1996 that would better meet their respective needs and better capitalize on their respective strengths.

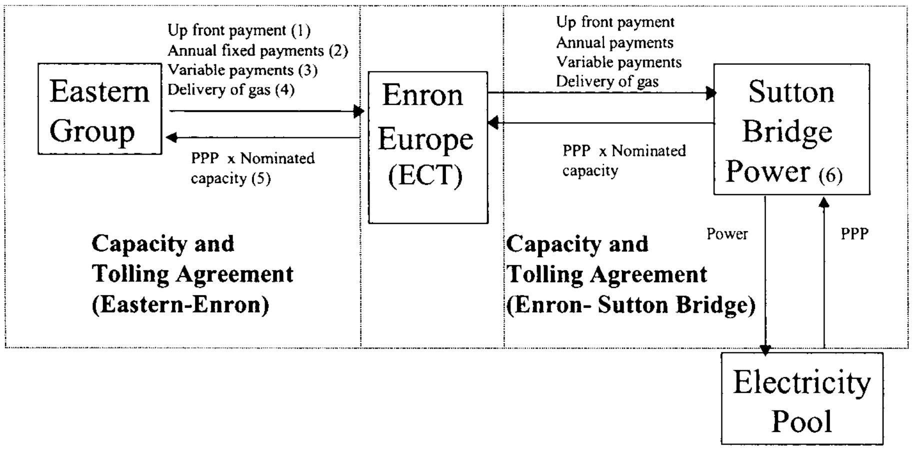
SUTTON BRIDGE: THE ALTERNATIVE PROPOSAL

Under the alternative proposal, Eastern would have a contractual interest in a synthetic or "virtual" plant, but no direct or indirect legal ownership whatsoever in a physical plant, nor any obligation to buy power at fixed prices. Instead, Eastern would have the right, but not the obligation, to deliver natural gas and receive cash payments equal to the market value of a certain amount of electricity. Unlike an IPP where Eastern was committed to buy a fixed quantity of electricity, this contract would allow Eastern to receive electricity proceeds only when it was economic to do so. If gas prices were low relative to electric prices, Eastern would exercise its contractual right to receive electricity proceeds. However, if gas prices were high relative to electric prices, Eastern could sell the gas in the market rather than convert it into electricity.

The alternative proposal involved two independent, though economically linked, Capacity and Tolling Agreements (CTAs), agreements that gave parties the right to exchange one commodity for the value of another. Exhibit 13-2 illustrates the fundamental

EXHIBIT 13-2

SCHEMATIC OF EASTERN–ENRON–SUTTON BRIDGE CTAs



(1) Eastern would pay Enron approximately £9 million up front.

(2) Eastern would make fixed annual capacity payments of £68.8 million per year.

(3) Eastern would make variable payments of £357.5 for every half hour the plant was operational.

(4) For each kWh that Eastern wished to receive PPP, it would deliver natural gas in the amount dictated by the contractual heat rate. Under a separate agreement with Enron, Eastern would buy this gas from Enron at the index price plus 2%.

(5) Eastern could nominate up to 700 MW in the summer and 735 MW in the winter. There would be pre-specified numbers of maintenance days during which the Eastern-Enron CTA would be suspended. The CTA would last 15 years.

(6) Enron would initially own Sutton Bridge, but was likely to sell part of its holdings to investors over time. Enron was contracted to build and operate the plant, but anticipated it would sign a contract with General Electric to perform these tasks.

Source: Sutton Bridge Term Sheets (Enron and Eastern).

contracts under the alternative proposal. The first CTA, between Eastern and Enron, would allow Eastern to exchange physical gas for power pool proceeds—this contract governed the virtual plant. Exhibit 13-3 summarizes the key aspects of the CTA between Eastern and Enron. To offset the risk from the Eastern CTA, Enron's traders could enter into an offsetting CTA with another party or they could construct a "hedge" using the physical plant at Sutton Bridge. By creating a second CTA between Enron and Sutton Bridge Power, the special purpose vehicle that would own the physical power plant, Enron would also have the right to exchange gas for power pool proceeds.

The Eastern-Enron Capacity and Tolling Agreement

Each day, Eastern could decide whether to exercise its option to exchange gas for pool proceeds over 48 half-hour periods for the following day.[14] The amount of gas required for delivery was based on the number of megawatts (MWs) nominated by Eastern—up to a maximum of 700 MW in the summer (April to September) and 735 MW in the winter (October to March). The amount of gas required would also be a function of a contractual "heat rate," the rate at which gas could be converted into electricity. Although the two parties had not yet agreed on a specific number, it would likely be somewhere between the heat rates for old and new CCGT technologies: 6,800 to 7,600 Btu per kWh (or 6.8 to 7.6 MMBtu/MWh; Exhibit 13-4 shows efficiencies, or heat rates, for various generating technologies). For example, if they agreed to a heat rate of 7,200 Btu/kWh and Eastern wanted to receive power pool proceeds for an hour on its full summer capacity of 700 MW, then it would deliver 5,040 MMBtus of gas (= 700 MWh × 1000 kWh/MWh × 7,200 Btu/kWh × 1 MMBtu/1,000,000 Btu) and would receive a payment equal to the market value of 700 MW for one hour at PPP.

According to the current term sheet, though subject to final revision, Eastern would pay a fixed charge, a variable charge, and other operating and maintenance expenses. The fixed charge or capacity payment of £68.8 million per year would cover all fixed costs and debt service requirements as well as provide a minimum return on equity capital for the actual plant. Thus, even if Eastern never asked for power proceeds and the actual plant was never actually used, the capacity payments alone would pay for the physical plant. The variable charge of £357.5 per half hour of plant operation would cover expected operating and maintenance expenses in the event Eastern did exercise its option to receive pool proceeds. Eastern would have to pay these variable costs on a minimum of 15,000 half-hourly periods each year. Finally, Eastern also agreed to cover all charges for transporting gas as well as start-up/shut-down expenses that were essentially similar to those incurred by the physical plant. Eastern agreed to pay gas transportation charges based on Transco's published rates for delivery to the physical plant. These costs averaged 10% to 15% of the total delivered gas cost.

The Enron-Sutton Bridge Capacity and Tolling Agreement

Under the second CTA, between Enron and Sutton Bridge Power, Enron would supply natural gas and pay fixed and variable costs in exchange for power pool proceeds. To the extent possible, the second CTA would mirror the first CTA between Eastern and ECT. However, key contractual features of the Enron-Sutton Bridge CTA would

[14] Rather than physically deliver gas to Enron, Eastern could obtain the gas from ECT. Eastern and Enron planned to sign an independent Gas Supply Agreement under which Eastern would pay Enron 102% of the monthly gas index whenever gas actually flowed, that is, whenever it was economic to operate the plant.

EXHIBIT 13-3

SUMMARY OF THE EASTERN/ENRON CAPACITY TOLLING AGREEMENT TERM SHEET

Definitions:

Owner	Enron or Affiliate
Offtaker	Eastern Electricity or Affiliate

Principles of Agreement:

The purpose of the Capacity and Tolling Agreement (CTA) is to establish the rights and obligations of the Parties in respect to the Offtaker's option. The Offtaker will pay the Owner Fixed Payments, Variable Payments, and other payments as specified in this agreement for the option ("CTA Option") to exchange natural gas for Pool proceeds.

Term: 15 years beginning May 1, 1999

Fixed Payments:

One-time up-front	£9 million
Annual	£68.8 million, payable on a daily basis

Variable Payments:

Rate	£357.50 per half-hour period of operation
Start-up/Shutdown	Each event will accrue two half-hour periods
Minimum	Offtaker will pay for at least 15,000 half-hour periods per year

Start-up Charge:

Offtaker will reimburse the Owner the cost of importing electricity for Start-Up.

Maximum Contractual Volume:

Summer	700 MW (April to September)
Winter	735 MW (October to May)

Offtake Instructions:

By 8:00 A.M. on the day prior to each Operating Day, the Offtaker will state:

(1) the number of half-hour periods and contractual volume for each period
- —if the contractual volume is zero for any period, it will be considered a Shut Down
- —each Shutdown will last for a minimum of four consecutive Half-Hour Periods
- —each Shutdown will incur a shut-down charge
- —the Offtaker is limited to 600 Start Ups in any three-year period

(2) an estimate of the volume of gas to be delivered

Planned Maintenance:

There will be 12 to 30 days of planned maintenance per year during which the CTA will be suspended.

Transportation Charge:

Offtaker will pay the Owner a transportation charge as follows:
Fixed: payable whether or not the CTA Option is exercised
Variable: payable only when the Off-taker elects to convert gas to electricity

Force Majeure:

The occurrence of a *Force Majeure* event will relieve both Parties from their obligations under the CTA, but only to the extent that the affected Party is prevented from complying with its obligations by the relevant Force Majeure event.

Credit Terms:

Each Party will provide reasonable credit support including a parent company guarantee. In addition, third-party credit support will be required if a party undergoes a material adverse change.

Source: Sutton Bridge Term Sheets (Enron and Eastern).

EXHIBIT 13-4

COMPARISON OF ALTERNATIVE GENERATION TECHNOLOGIES

Generating Technology[a]	Efficiency[b] Best Case (LHV)	Efficiency[b] Typical (HHV)	Heat Rate (MMBtus per MWh)[c]	Cost to build (per KW)[d]
OCGT—Old construction	30%	27%	12.6	n/a
OCGT—New construction	40%	36%	9.5	\$250–\$400
CCGT—Old construction	50%	45%	7.6	n/a
CCGT—New construction	56%	50%	6.8	\$500
Rankine Cycle Steam—Old construction	37%	33%	10.2	n/a
Rankine Cycle Steam—Sub-critical	40%	36%	9.5	\$550
Rankine Cycle Steam—Super-critical	45%	41%	8.4	\$600
Diesel	42%	38%	9.0	\$270

[a] Technologies: OCGT = open cycle gas turbine; CCGT = combined cycle gas turbin. The Sutton Bridge plant would use newer CCGT technology.

[b] Best case efficiency assumes that all possible energy in a fuel can be used in producing electricity (i.e., there are no losses). Typical efficiency reflects some expected loss of energy in converting fuels to electricity.

[c] The Heat Rate is the number of MMBtu's needed to produce 1 megawatt-hour (MWh). Lower numbers represent more efficient technologies.

[d] Cost to build excludes financing costs and reflects estimates of EPC contracts available in late 1996.

Source: Enron Corporation

reflect the plant's *actual* physical properties (capacity, heat rate, and maintenance costs) whereas the Eastern-Enron CTA would reflect *contractual* levels of these aspects of plant operation. This structure would leave Enron exposed to the differences between actual and contracted levels of plant performance. Both agreements would begin in late spring of 1999 and last 15 years, even though the plant would have a useful life of perhaps 30 years. Exhibit 13-5 provides current capital market data; Exhibit 13-6 provides financial projections for the two CTA agreements.

The Physical Plant at Sutton Bridge

As of December 1996, Enron had received regulatory permission to build a 700 MW power plant. Enron engineers estimated it would take approximately two years to construct the power island (the generator itself), the 2.2 km gas pipeline from the national transmission system to the plant, and the 3.5 km overhead transmission line from the plant to the national electricity grid. Once complete, the plant would operate in two distinct phases: a 15-year CTA phase during which Enron claimed the plant's output followed by an indefinite merchant phase.[15] Enron managers expected to fund construction and repay debt prior to the merchant phase even though the exact details of the financial plan had not yet been worked out. Exhibit 13-7 provides a breakdown of sources and uses of funds for the construction of the physical plant.

[15] Enron would have the right to extend its CTA on an annual basis at the end of the initial 15-year term.

EXHIBIT 13-5

US AND UK INTEREST RATES AS OF NOVEMBER 29, 1996

	Maturity					
	1 Year	2 Year	3 Year	5 Year	10 Year	15 Year
Rates in £ (UK pounds):						
Government bonds	6.61%	6.74%	6.76%	7.04%	7.35%	7.57%
A-rated corporate bonds	6.57%	6.98%	7.11%	7.47%	7.98%	8.26%
BBB-rated corporate bonds	6.79%	7.12%	7.33%	7.73%	8.20%	8.68%
Rates in $ (US dollars):						
Government bonds	5.36%	5.60%	5.71%	5.83%	6.05%	6.11%
A-rated corporate bonds	5.77%	5.95%	6.08%	6.24%	6.61%	6.83%
BBB-rated corporate bonds	5.96%	6.10%	6.22%	6.45%	6.79%	7.05%

Source: Adapted from Bloomberg. All rates quoted on a semiannual basis.

Enron, as the general contractor for the project, agreed to sign a fixed-price, date-certain, turnkey contract for construction, and to pay liquidated damages for either completion delays or substandard performance. The plant would contain two 260 MW gas turbines and a linked 270 MW steam turbine giving it a potential output of 790 MW, and the ability to produce 760 MW of power in the winter and 743 MW in the summer. Because Enron had regulatory approval to produce only 700 MW of power, it had applied for, and expected to get, approval for the additional 90 MW of generating capacity.

Enron planned to subcontract the manufacture and installation of the turbines to General Electric (GE), a AAA-rated company with extensive experience in constructing and operating power generating equipment. GE proposed to use its newest turbines, the 9FA+, even though early versions of the turbines had experienced high failure rates. GE had analyzed the problems, corrected the design flaws, and was seeking commercial applications for the redesigned turbines. If the new design worked as expected, Sutton Bridge would be among the most efficient gas plants in the industry (see Exhibit 13-4). GE indicated a willingness to provide a "new product" guarantee against completion delays and performance problems. Specifically, GE was willing to guarantee a minimum heat rate of 6,950 Btu/kWh. While such completion guarantees subject to performance targets were standard practice in the industry, GE was willing to go one step further by guaranteeing minimum performance levels for the life of the project. If the turbines failed to achieve minimum performance levels, GE would pay liquidated damages to cover the difference. At the same time, any contract would likely include bonuses for availability and efficiency above the contracted rates.

Once the plant passed a series of completion tests, which would be verified by an independent consultant, it would enter the CTA phase. During this phase, the plant would be exposed to neither fuel nor pool price risk regardless of use, because Enron's payments would cover all fixed and operating costs. Enron expected that GE would operate the plant subject to a fixed-price management fee. This arrangement was unique because Enron engineers were usually responsible for daily operations at Enron plants. Yet the arrangement fit with GE's desire to expand its service operations. Jack Welch,

EXHIBIT 13-6

FINANCIAL PROJECTIONS UNDER THE TWO CTA AGREEMENTS

	Eastern Payments (Eastern/Enron CTA)		Sutton Bridge Power Operating & Maintenance Expenses (Enron/Sutton Bridge CTA)		
Year	**Fixed**	**Variable**	**Fixed**	**Variable**	**Other**
1999	£57.6	£3.7	£5.2	£3.7	£ 7.2
2000	68.8	4.5	6.3	4.5	9.0
2001	68.8	4.5	6.5	4.5	9.1
2002	68.8	4.6	6.7	4.6	9.4
2003	68.8	4.5	6.9	4.5	9.7
2004	68.8	4.2	7.1	4.2	10.0
2005	68.8	4.7	7.4	4.7	10.2
2006	68.8	4.8	7.6	4.8	10.4
2007	68.8	4.9	7.8	4.9	10.8
2008	68.8	5.1	8.0	5.1	11.2
2009	68.8	5.1	8.3	5.1	11.4
2010	68.8	4.6	8.5	4.6	11.8
2011	68.8	5.3	8.8	5.3	12.1
2012	68.8	5.2	9.0	5.2	12.5
2013	68.8	5.3	9.3	5.3	12.8
2014	68.8	1.8	9.6	1.8	13.2

Notes: Assumes the Enron/Sutton Bridge CTA begins on March 1, 1999. The columns "Eastern payments" represent planned payments from Eastern to Enron under their CTA agreement, assuming the CTA is fully exercised. These exclude gas transportation charges, which Eastern would pay to Enron. The "Sutton Bridge Operating and Maintenance Expenses" include the costs to operate the plant but do not include financing charges.

Sutton Bridge Power would pay taxes at the rate of 33%. It would enjoy depreciation tax shields from tangible assets assuming straight-line depreciation over 40 years (the plant's useful life), and interest tax shields from debt payments assuming 15-year amortization and a debt rate of 8.75%.

Asset betas for utilities in the United States and the United Kingdom with gas-fired capacity ranged from 0.26 to 0.45 during 1996. The historical equity risk premium in the U.K. market (i.e., the arithmetic average of the spread between equity returns and long-term U.K. Gilts) was 7.94% from 1919 to 1993 (*Source:* Barclays de Zoete Wedd Securities Ltd., *The BXW Equity-Gilt Study*, 39th ed., January 1994).

Source: Enron, casewriters' estimates.

GE's CEO, commented: "Our job is to sell more than just the box. . . . We're in the services business to expand our pie."[16]

Another novel feature of this structure was that Enron traders would play a central role in determining operating or dispatch decisions. As a result, the plant would become part of their risk books containing the firm's long and short positions in gas and power. This organizational structure ensured that the plant would run only when it was

[16] Tim Smart, "Jack Welch's Encore," *Business Week*, October 28, 1996, p. 154.

EXHIBIT 13-7

SUTTON BRIDGE CONSTRUCTION SOURCES AND USES OF FUNDS

	£ (in millions)
Sources of Funds	
Debt Proceeds	£286
Capital Contributions from Shareholders	42
Operating Cash Flow Post-Completion Date	9
Total Sources of Funds	**337**
Uses of Funds	
Construction Costs	£240
Financing, Legal and Consultants Fees	16
Construction Insurance	6
Development Costs and Fees	26
Interest During Construction (net)	31
Other Fees & Expenses	18
Total Uses of Funds	**337**

Source: Enron.

optimal to do so, that is, when the gas input price plus operating expenses were less than pool prices. (Exhibit 13-8 shows the historical price differential between the gas cost needed to produce one megawatt-hour of power and the actual price per megawatt hour of power produced assuming highly efficient gas production technology.) In contrast, a power plant operating under an IPP structure would run continuously regardless of current market conditions.

After CTA phase ended, the plant would enter a merchant phase in which it would be exposed to both fuel and pool price risks. At that time, the plant's ability to service its debt and provide equity returns would be a function of its ability to burn gas to generate competitively-priced power. According to independent gas experts, Sutton Bridge would "have a wide choice of gas suppliers and a range of flexible contract terms beginning in 2014 and extending through 2022."

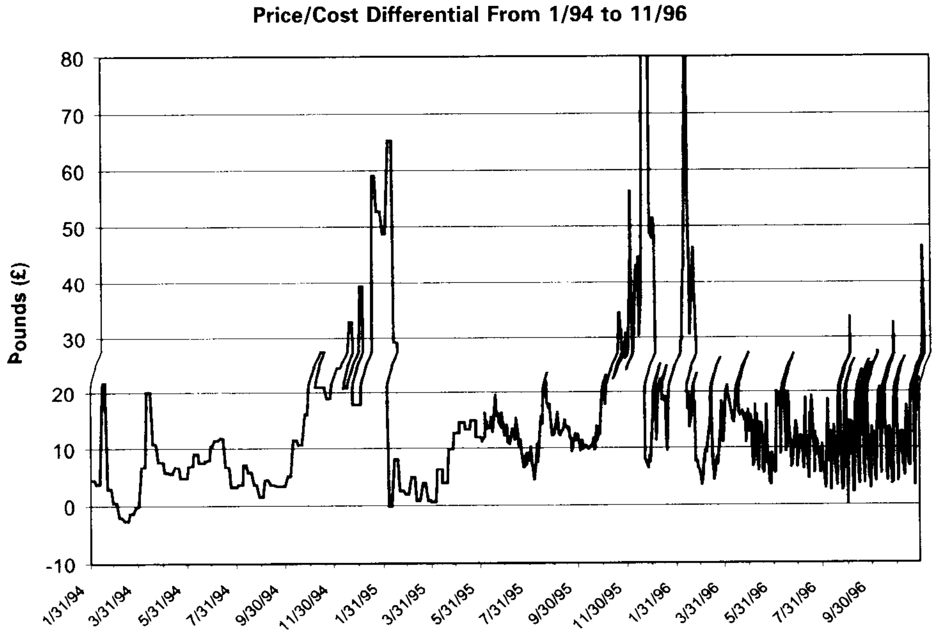
Because of the risk during the merchant phase, the Enron team figured that most, if not all, the project debt would have to be repaid during the CTA phase. The current plan called for 15-year commercial bank loans to finance construction, though Enron would, if possible, issue longer-term project bonds. Enron's treasury group assured the deal team that they could finance the deal as long as Enron Corporation guaranteed the Enron/Sutton Bridge Power CTA. With these assurances, the team concentrated on working out the commercial and physical details, leaving the financing details to be resolved at a later date.

DECISIONS

The alternative proposal, though novel in many respects and risky in untraditional ways, held great appeal for both Eastern and Enron. For Eastern, this deal would cement its transformation into an integrated energy company competing in a deregulated environment. Under the alternative structure, Eastern would have an outlet for its gas re-

EXHIBIT 13-8

PRICE/COST DIFFERENTIAL FOR THE PRODUCTION OF ONE MWH *USING CCGT TECHNOLOGY (1/94 TO 11/96)*



Note: This graph shows the difference between the average daily price of one MWh of electricity and the cost of the gas needed to produce one MWh of electricity using efficient CCGT technology. It is calculated using the formula: Differential = market price of one MWh − (7.400 * cost of one MMBtu), where the implied heat rate is 7.400 MMBtus per MWh. The calculation does not include transportation, variable tolling, or fixed costs. The calculation uses weekly data prior to June 1996 and daily data thereafter.

Source: Casewriters' calculations.

serves as well as additional capacity for its trading operations. The virtual plant would therefore be consistent with its desire to arbitrage between the gas and electricity markets on a daily basis. Like Eastern, Enron saw the deal as a way to further develop its European trading operations and strengthen its reputation as an innovator in the rapidly changing European energy markets.

While Seeligson and Danielsen had kept their respective managers informed about the status of the deal over the course of the past six months, they now had to agree on a contractual heat rate and get formal approval for the deal. Each set of executives had to make sure that the proposal made strategic and financial sense, that it would deliver an appropriate financial return, and that the risks were commensurate with the returns. From Enron's perspective, it still had to structure the special purpose company known as Sutton Bridge Power, agree on a financial structure for the actual plant, draft the legal documents, and figure out how to value and "book" the transactions. Because Enron was the only nonfinancial firm to adopt "mark-to-market" accounting rules, this final step was likely to be complex.

GLOSSARY

Btu: British thermal unit, the amount of heat needed to raise the temperature of one pound of water by one degree Fahrenheit

—**MBtu** = 1,000 Btu's

—**MMBtu** = 1 million Btu's

CCGT: combined cycle gas turbine

CFD: contract for differences

CTA: capacity tolling agreement

De-loading: the process of shutting down a power plant

ECT: Enron Capital & Trade Resources Corporation, a Delaware corporation

EFA: electricity forward agreement

EPC Contract: engineering, procurement, and construction contract

Half-hour period: *one of 48 time slots in which power is sold in the U.K. market*

Heat rate: a measure of fuel conversion efficiency. A heat rate of 8,150 requires 81.50 therms to produce each MWh of power

IPP: Independent power plant

MPP: merchant power plant, a plant with uncertain electricity output prices and quantities

National Grid: the high-voltage national electricity transmission system operating primarily in England and Wales which offers connections to and use of the system to generators and suppliers of electricity

National Transmission System (NTS): the main pipeline system operated by Transco for the conveyance of gas in Great Britain

OFFER: the Office of Electricity Regulation (U.K. power regulator)

Power island: the power plant's generating and other associated equipment

PPA: power purchase agreement, an agreement to buy a given amount of power at a given price

PPP: pool purchase price consisting of the system marginal price (SMP) plus a capacity payment

REC: the 12 regional electric companies that came into existence in 1990 as a result of the restructuring and privatization of the electricity supply industry in England and Wales

SBP: Sutton Bridge Power, a company incorporated in England and Wales with unlimited liability

SMP: system marginal price

Take-or-pay contract: a contract obligating a firm to buy a fixed quantity of gas at fixed prices, similar to a forward contract

Therm: a measure of heat content of a fuel—10 therms equals 1 MMBtu equals 2.927 kilowatt hours

Transco: the manager of the National Transmission System (NTS)

Uplift: includes all additional costs incurred by the Pool

Watt: a unit of electric power equal to the power in a circuit in which a current of one ampere flows across a potential difference of one volt

—**kW:** kilowatt is 1,000 watts

—**kWh:** kilowatt-hour is 1,000 watts for one hour

—**MW:** megawatt is 1 million watts

—**MWh:** megawatt-hour is 1 million watts for one hour

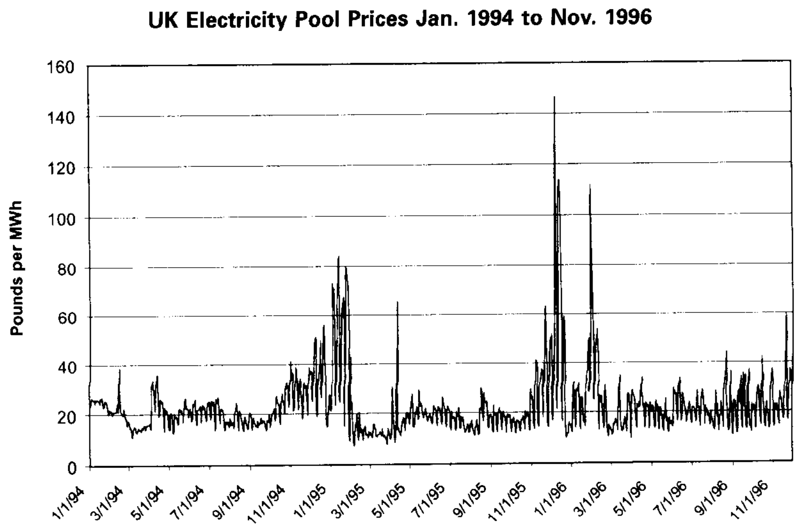
—**GWh:** gigawatt-hour is 1 billion watts for one hour

APPENDIX

U.K. GAS AND ELECTRICITY MARKETS

EXHIBIT 13-A1

U.K. ELECTRICITY POOL PRICES, JANUARY 1994 TO NOVEMBER 1996

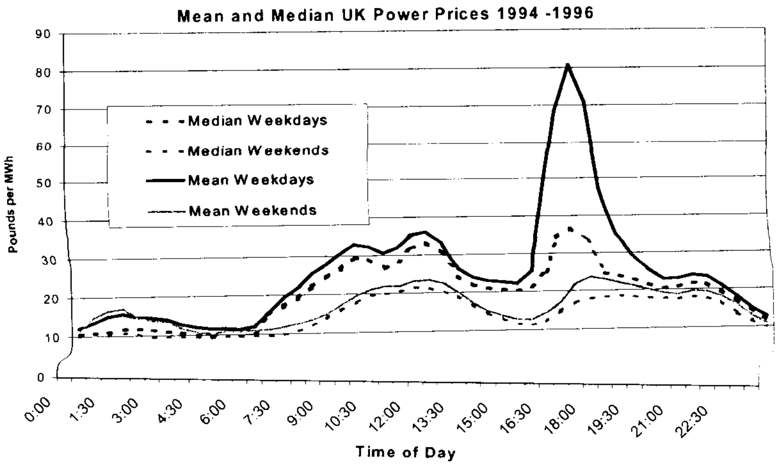


Note: The prices shown were the arithmetic averages of the 48 half-hourly pool prices posted each day, but do not take into account the volume of power delivered in each half-hour period. The price was reported in pounds per megawatt hour (£/MWh). The average price of electricity on November 29, 1996, it was £33.62/MWh; during the month of November 1996, it was £26.57/MWh; and throughout the previous 12 months, it was £25.26/MWh.

Source: Enron Corporation.

EXHIBIT 13-A2

POOL PRICES BY HALF-HOUR PERIOD



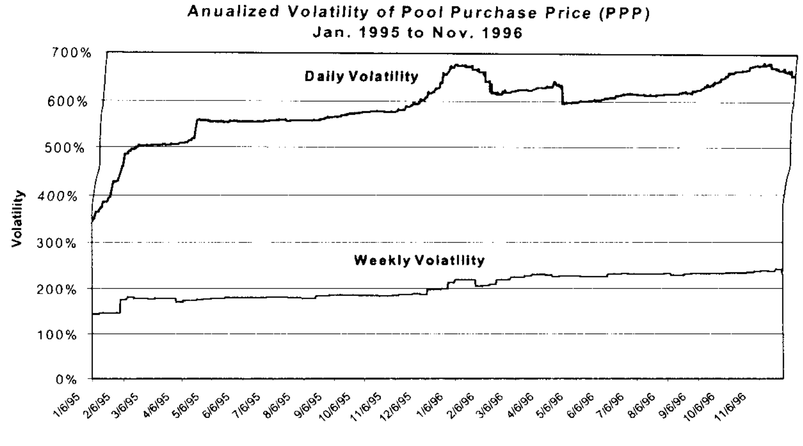
Note: This figure plots the mean and median PPP for weekdays and weekends as a function of the time of day over the prior two years.

Source: Casewriters' calculations.

(*Continued*)

EXHIBIT 13-A3

VOLATILITY OF THE AVERAGE POWER POOL PRICE

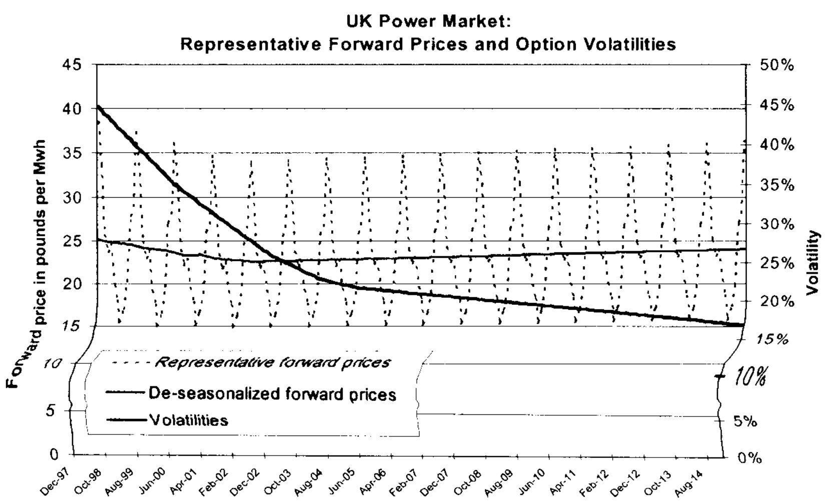


Note: Historical volatility is measured by the standard deviation of the natural log of daily (and weekly) electricity price changes over the previous 365 days. (The price change is defined as the ratio of the price on a given day (week) over the price on the prior day (week).) The historical volatility of the daily and weekly average electricity prices was 654% and 232%, respectively, as of 11/29/96.

Source: Casewriter calculations.

EXHIBIT 13-A4

PROJECTIONS OF FORWARD PRICES AND VOLATILITIES IN THE U.K. POWER MARKET



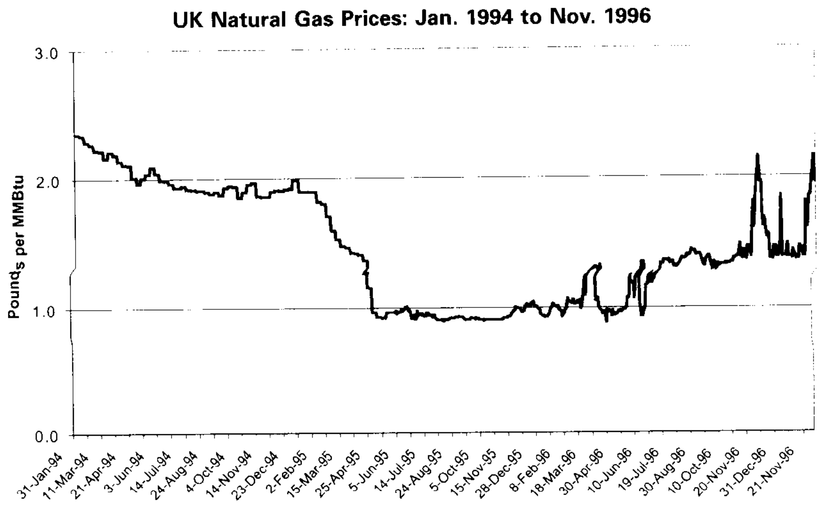
Note: This figure shows "representative" forward prices and volatilities for contracts with maturities of one year and longer. They do not represent Enron's positions or beliefs. The "saw tooth" pattern of the forward prices represents anticipated seasonality of prices. Short-term (one month) implied volatilities were about 50% annually. The implied convenience yields for maturities of one to five years ranged from 7% to 10%.

Source: Enron Corporation.

(*Continued*)

EXHIBIT 13-A5

U.K. NATURAL GAS PRICE DATA

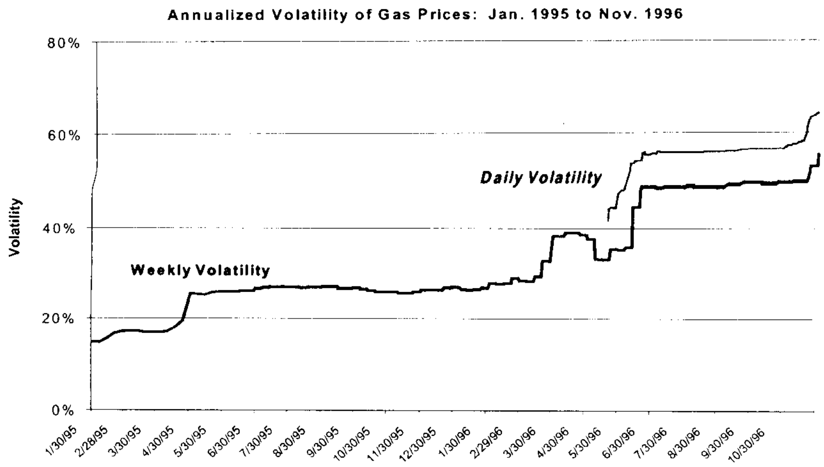


Note: These prices were the day-ahead prices expressed in pounds per MMBtu. Weekly data were available through June 2, 1995, daily prices were available thereafter. The average price of gas on November 29, 1996, was £1.95/MMBtu; during November 1996, it was £1.59/MMBtu; and during year-to-date (YTD) 1996, it was £1.28/MMBtu.

Source: PH Energy Analysts Ltd.

EXHIBIT 13-A6

HISTORICAL VOLATILITY OF U.K. NATURAL GAS PRICES



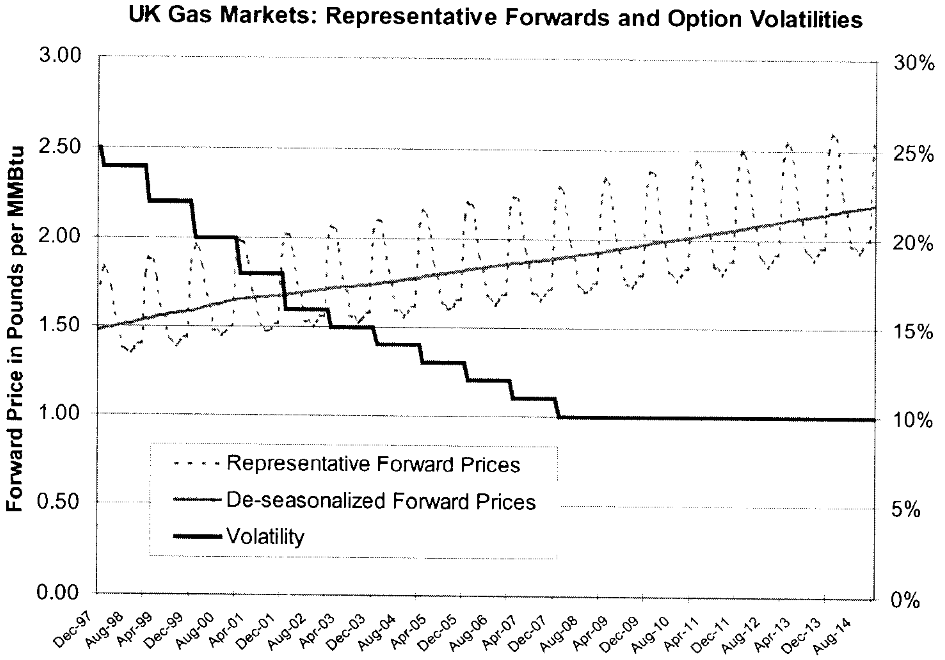
Note: Historical volatility was measured by the annualized standard deviation of the natural log of gas price changes over the prior year. The volatility for the daily data starts in June 1996, a year after the daily data became available. The historical volatility based on the price of natural gas on November 29, 1996, was 64% using weekly data, and 55% using daily data. Short term (one month) implied volatilities were approximately 45% annually.

Source: PH Energy Analysts Ltd.

(Continued)

EXHIBIT 13-A7

PROJECTED FORWARD PRICES AND VOLATILITIES IN THE U.K. NATURAL GAS MARKET



Note: These estimates were "representative" forward prices and volatilities for contracts with maturities of one year or longer. They do not represent Enron's positions or beliefs. The "sawtooth" pattern of the forward prices represents anticipated seasonality of prices. The implied convenience yields on a one-year forward contract were approximately 31%.

Source: Enron Corporation.